

Use Spread-Sheet Based CHP Models to Identify and Evaluate Energy Cost Reduction Opportunities in Industrial Plants

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ABSTRACT

CHP for (Combined Heat and Power) is fast becoming the internationally accepted terminology for describing the energy utilities generation and distribution systems in industrial plants. The term is all inclusive - boilers, fired heaters, steam turbines, gas turbines, expanders, refrigeration systems, etc.

A simulation model of the CHP system is an extremely useful tool to understand the interactions between the various components. Applications include:

- ◆ Identifying opportunities for cost reduction through efficiency improvement.
- ◆ Accurate energy cost accounting.
- ◆ Evaluating the energy cost impact of proposed process changes on the demand side.
- ◆ Comparison of cogeneration options.
- ◆ Identifying load shaping strategies (eg. switching between motors and turbine drives).
- ◆ Negotiating fuel/power supply contracts.

This paper describes how CHP models can be developed easily and at low cost using electronic spreadsheets, and illustrates their application with a detailed example.

INTRODUCTION

The "utilities" plant at an industrial manufacturing facility should more properly be called the Combined Heat and Power, or CHP, system. This is the prevailing terminology used in Europe and elsewhere in the world, and is increasingly being adopted in the USA as well. The CHP system includes all the elements involved in the genera-

tion and distribution of energy to drive the process and supporting infrastructure:

- ◆ Fired boilers.
- ◆ Waste heat boilers.
- ◆ Combustion air preheaters.
- ◆ Economizers (for BFW preheat).
- ◆ Blowdown flash tanks.
- ◆ Condensate recovery systems (steam traps, separators).
- ◆ Condensate mix tanks.
- ◆ Deaerators.
- ◆ BFW pumps.
- ◆ Back-pressure steam turbines.
- ◆ Pressure reducing stations.
- ◆ Desuperheating stations.
- ◆ Gas turbines, with or without heat recovery steam generators.
- ◆ Condensing steam turbines.
- ◆ Condensers.
- ◆ Cooling water circuits.
- ◆ Refrigeration systems (both mechanical and absorption type), etc.

The interactions between these various components can be very complex, and cannot be easily understood without constructing a reasonably accurate mathematical model.

CONSTRUCTING THE MODEL

A model is simply a set of equations and constraints that establishes the quantitative relationship between the key parameters of interest.

Consider the CHP system for a pulp/paper mill, as depicted in Figure 1, which incorporates many of the features found in a typical industrial facility.

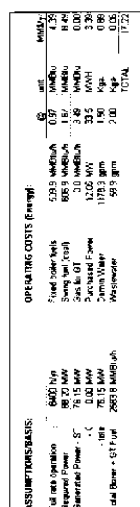
The overall model has two distinct elements:

- a) Models of individual items of equipment.
- b) Computational strategy for interactions between equipment, that also reflects the operating policy.

It is beyond the scope of this article to describe all possible variations of equipment models, but some selected examples will illustrate the available options for the principal items.

AVERAGE STEAM COSTS			
	Base	New	Savings
500,000 lbs/yr (gross generating cost)	\$18	\$18	0.000%
1.00 lbs/lb (gross generating cost)	17.22	17.219	0.000%
1.25 lbs/lb (net to process)			0.000%

Adjusted steam cost: n/a \$/000



Boiler Model One (Simple)

Operating mode = base load, constant efficiency

Input parameters = max operating capacity, operating pressure and temp, efficiency, blowdown rate (as percentage of steam generation), operating rate (percentage of max).

Equations:

1. Steam gen = capacity x operating rate
2. Blowdown = fraction x steam gen rate
3. Feedwater = stm gen + blowdown
4. $H_s = f(P, T)$, from steam properties data base
5. Fuel input = $Stm (H_s - h_{BFW})/h$

Boiler Model Two (Simple)

Operating mode = swing, variable efficiency

Input parameters = max operating capacity, operating pressure and temp, blowdown rate (as percentage of steam generation)

Equations:

1. Steam gen = Total steam production required (trial value in overall computational algorithm) – combined steam generated in all other boilers
2. Blowdown = fraction x steam gen rate
3. Feedwater = stm gen + blowdown
4. $H_s = f(P, T)$, from steam properties data base
5. Operating rate (%) = $Stm\ gen / Capacity$
6. Efficiency $h = f(\text{operating rate})$, equation to be provided by user, from manufacturer's data
7. Fuel input = $Stm (H_s - h_{BFW})/h$

Boiler Model Three (Rigorous)

Operating mode = base load

Input parameters = max operating capacity, operating pressure and temp, blowdown rate (as percentage of steam generation), operating rate (percentage of max), stack gas temp, combustion air supply temp, excess air ratio, radiative and convective heat losses

Equations:

1. Steam gen = capacity x operating rate
2. Blowdown = fraction x steam gen rate
3. Feedwater = stm gen + blowdown

4. $H_s = f(P, T)$, from steam properties data base
5. Efficiency $h = \text{calculated from boiler heat and material balance}$
6. Fuel input = $Stm (H_s - h_{BFW})/h$

Back-Pressure Steam Turbine (Simple)

Operating mode = constant load and flow

Input parameters = P_i , T_i , P_o , steam flow in (Klb/h), power output rate (kwh/Klb). The latter is calculated by the user from inlet and outlet pressures, inlet temp, and isentropic efficiency.

Equations:

1. Power, kw = output rate x steam flow
2. $H_{s,o} = H_{s,i} - 3412/kw$
3. $T_o = f(P_o, H_{s,o})$, from steam props data base

Back-Pressure Steam Turbine (Rigorous)

Operating mode = load following, variable flow

Input parameters = P_i , T_i , P_o , power output required, linked to process model, turbine performance curve (from manufacturer's data) that expresses the steam flow rate as a function of power output for the given P_i , T_i , and P_o .

Equations:

1. Steam flow = $f(\text{required power output})$
2. $H_{s,o} = H_{s,i} - 3412/kw$
3. $T_o = f(P_o, H_{s,o})$, from steam props data base

Deaerator

Operating mode = steady state (see Figure 2 on next page)

Input parameters = condensate flow and temp from process, condensate flow and temp from condensing steam turbine, economizer duty, pressure of steam used in economizer, DA operating pressure, temp of makeup water (after preheating), vent vapor flow from DA

Equations:

1. Combined condensate flow, $C = \text{process cond} + \text{turbine condensate} + \text{economizer condensate}$
2. Mixed cond temp = $\text{sum}(\text{flow} \times \text{temp}) / \text{sum}(\text{flow})$

3. Assume $H_v = H_s$ (this simplifies the model without significant error)
4. BFW flow, $B = \text{sum (feedwater flows to boilers)} + \text{sum (flows to desuperheating stations)}$
5. $SDA = \{C(h_M - h_C) + B(h_B - h_M)\} / (H_s - h_M) + V$
6. Makeup to DA, $M = B + V - C - S_{DA}$

Other Equipment

Similar models must be set up for the blowdown flash tank, desuperheating stations, etc.

Overall Algorithm

Now we need to tie all the various parameters together in an overall computational algorithm. It is recommended that heat losses due to radiation and leaks be excluded from the model, as they add a tremendous amount of computational complexity, make the model extremely difficult to debug, and do not offer compensating benefits. The typical error is about 3 percent, and this can be added on to the fuel cost.

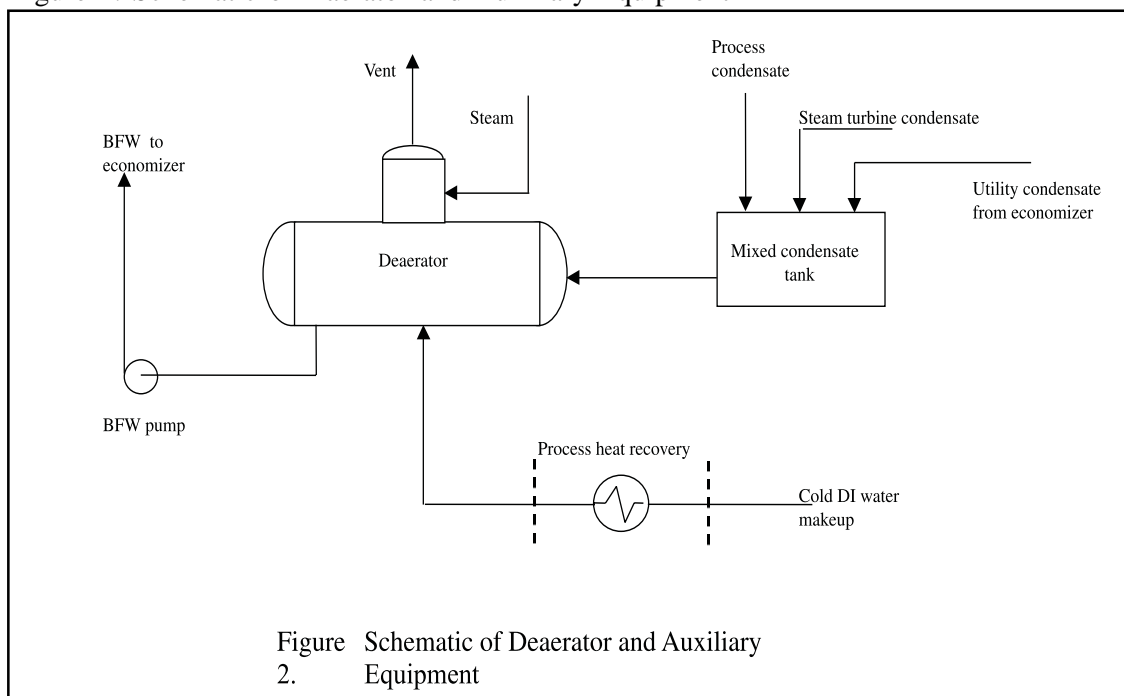
Input parameters = operating pressure and temp of the various steam headers, process steam demands at the various pressure levels, steam flow rates to the back-pressure and condensing turbines, condensate return rate (flow), DI makeup water supply temp, estimated or allowable vent losses from LP header.

Calculation sequence:

Assume a trial value for total steam generation in the boilers, and then calculate the various parametric values from the "top down" by applying established principles for steady-state material and energy balances.

1. PRV flow from HP to IP = $\text{sum (steam from boilers)} - \text{process demand} - \text{sum (turbine outflows)}$
2. Calculate BFW flow to DSH station in IP header by simultaneous material and heat balance
3. PRV flow from IP to MP = $\text{sum (steam in-flows)} + \text{DSH stm} - \text{process demand} - \text{sum (turbine outflows)}$
4. Calculate BFW flow to DSH station in MP header by simultaneous material and heat balance
5. PRV flow from MP to LP = $\text{sum (steam in-flows)} + \text{DSH stm} - \text{process demand} - \text{sum (turbine outflows)}$
6. Calculate BFW flow to DSH station in LP header by simultaneous material and heat balance
7. Calculate flash vapor and net liquid blowdown flows from the BD flash tank, by heat/mass balance.
8. Calculate steam and makeup water flows to the DA from DA model

Figure 2. Schematic of Deaerator and Auxiliary Equipment



9. BFW temp = DA temp + economizer duty / B
10. Vent flow from LP header to atmos = sum (steam inflows) + DSH stm + flash vapor from BD tank - process demand - stm to DA
11. Heat recovery required against process hot streams = $M \times (DA \text{ feed temp} - DI \text{ makeup water supply temp})$
12. Calculate total steam generation required in boilers = sum (process demands) + flow to condensing path of steam turbine + steam to economizer + DA steam - BD flash vapor - sum (DSH flows) + LP vent to atmos

Compare the calculated steam generation requirement with the assumed trial value, and iterate until the two agree within the specified tolerance limit (eg. 0.1 Klb/h).

One note of caution – the user should be careful to ensure that the assumptions and data inputs do not result in infeasible solutions, such as reverse flows (ie from lower to higher pressure) across the PRV, and violating capacity constraints on the boilers and turbines.

APPLICATIONS

Now let us consider some of the practical uses for this model.

First and foremost, we compare the calculated steam and power balance against measured (metered) values. If the two are not in reasonable agreement it means one of two things:

- a) The meters need to be recalibrated.
- b) The model is not an accurate representation of the plant, and needs to be corrected.

The error could be in the physical configuration, or in the assumptions about operating policy and/or leaks and heat losses.

Once the data have been reconciled, it is possible to begin analyzing the system for opportunities to improve efficiency. The first thing we look for is shifting flow from PRVs to steam turbine generators. In Figure 1, we see that the PRV flows are already very small, and that the opportunity to make more power in the back-pressure STs is limited.

We next turn our attention to condensing steam turbines. These are usually “Across the Pinch,” and not cost effective for base load operation. The model shows however that if the condensing flow were reduced to the minimum of 20Klb/h, the operating cost would go up by \$630K per year, which is counter to expectation. This is because the swing fuel being used is coal (in power boiler #10), which is extremely cheap.

If the swing fuel were gas, however, then the cost savings would be \$910/yr, which is more typical, and would be accomplished by shutting down package boilers #5 and 6. The model shows that nearly a million dollars a year (including maintenance and operating labor cost savings) could be achieved by minimizing flow through the condensing section of the turbines, at zero capital cost.

The next idea we explore is to increase the duty on the economizer, e.g. from 10 MMBtu/h to 30 MMBtu/h. This will mean adding additional heat transfer surface. However, the model shows that the cost savings are non-existent, because the incremental power credit is almost exactly offset by the extra cost of fuel. Thus at current fuel and power prices, there is no incentive to spend any engineering resources on repairing/revamping the economizer. In fact, the model shows that the economizer could be taken out of service with no penalty at all. This insight would probably have eluded us without a model.

Such preliminary screening allows us to focus on the projects that are attractive, and cast aside ones that are not. We can simultaneously evaluate the potential benefits of common energy conservation and efficiency improvement measures such as increasing the condensate recovery rate, preheating BFW makeup water to the DA, and reducing steam consumption in the process through heat recovery.

For example, increasing condensate recovery from 56 percent to 70 percent saves 410 K/yr, while adding an exchanger to recover 5.5 MMBtu/h of heat from boiler blowdown saves about \$110K/yr, and further preheating BFW makeup by 26 MMBtu/h to 150°F (against process waste heat) saves another \$190K/yr. It may appear odd that

Table 1. Summary of Cost Savings from Various Projects

	Case Number								
	0	1	2	3	4	5	6	7	8
Economizer duty, MMBtu/h	10	10	10	30	0	10	10	10	10
Condensate recovery, %	56	56	56	56	56	70	70	70	70
DA feedwater temp, F	73	73	73	73	73	73	150	150	150
Heat rec into DFW, MMBtu/h	0	0	0	0	0	0	31.5	26.7	26.7
Process LP steam savings, Klb/h	0	0	0	0	0	0	0	200	200
Total boiler steam gen, Klb/h	1591	1479	1477	1494	1468	1439	1380	1270	1162
Fuel consumed, MMBtu/h									
Coal	607	450	545	557	538	492	409	86	8
Gas in boilers	98	98	0	0	0	0	0	0	0
Gas Gas Turbine	0	0	0	0	0	0	0	0	248
Total	705	548	545	557	538	492	409	86	256
Turbogenerator steam flows									
HP to IP	200	200	200	200	200	200	200	200	200
HP to MP	486	486	486	505	480	486	486	486	486
HP to LP	680	646	646	643	643	608	549	330	330
HP to condensing	100	20	20	20	20	20	20	20	20
Total	1466	1352	1352	1368	1343	1314	1255	1036	1036
Total power generated, MW	76.2	66.1	66.1	66.6	65.6	63.9	60.6	48.1	61.7
Operating cost, MM\$/yr	17.22	17.85	16.31	16.32	16.32	15.91	15.61	14.56	16.93
Cumulative savings, MM\$/yr	0	-0.63	0.91	0.90	0.90	1.31	1.61	2.66	0.29
Incremental savings, MM\$/yr	0	-0.63	1.54	-0.01	0.00	0.41	0.30	1.05	-2.37

Case Number Description

- 0 Base case-existing operation
- 1 Minimize condensing turbine flow, cut back on coal fired boiler
- 2 Minimize condensing turbine flow, cut back on gas-fired boilers (can be shut down)
- 3 Increase economizer duty to 30 MMBtu/h
- 4 Reduce economizer duty to zero
- 5 Increase condensate recovery from 56 percent to 70 percent
- 6 Raise DA feedwater temp to 150° F by heat recovery against process
- 7 Reduce LP steam demand in process through heat recovery (Pinch Analysis)
- 8 Add new 15 MW Gas

Note: Numbers in bold in the table are the primary changes made in each case listed.

the cost savings are not proportional to the heat recovery rate. This is because the reduction in steam generation comes from different boilers which have different efficiencies, an effect that would have been difficult to predict without the model.

In recent years, cogeneration projects involving gas turbines have become very popular. The model can be used to quickly check whether such a project would be appropriate for local site conditions. The key parameters (heat rate and steam/power ratio) for the machine being considered must be provided as input. The model shows that energy operating costs actually increase by \$2.37 MM/yr, because the power:gas cost ratio is not favorable, and so this project can be immediately rejected without further waste of time.

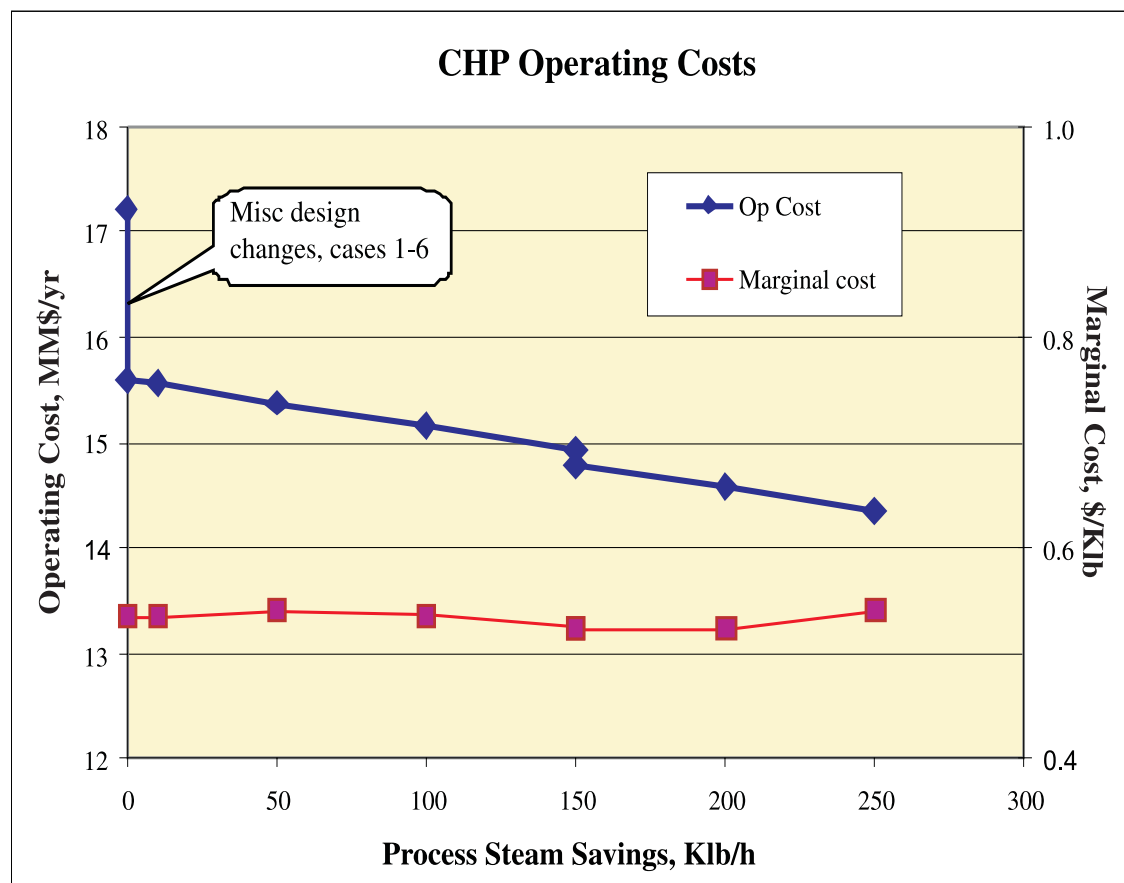
One must keep in mind that the foregoing conclusions are valid only for the fuel/power costs and equipment capacity/efficiency numbers that have been used. Under a different set of technical and economic conditions, the optimum operating policy could be quite different. The esti-

mated cost savings and key parameters for all of the various projects discussed above are summarized in Table 1.

Finally, we can postulate various levels of steam savings in the process, in steps of 50 Klb/h, and develop a curve showing the net cost savings and the marginal cost of steam. Figure 3 shows the marginal cost of steam savings is constant over the entire range of 0-250 Klb/h, which is somewhat atypical. Normally, there will be several step changes in the marginal cost curve, reflecting changes in fuel mix (eg. gas vs coal) and boiler efficiency as the high cost boilers are shut down, changes in steam path (eg. PRV versus ST) due to capacity limitations, or changes in power cost structure as due to contractual constraints.

It is important to recognize that the cost savings achieved are a function of the order in which the projects are implemented. Generally, the earlier projects will have proportionately larger savings, and the later ones will have smaller savings.

Figure 3. Operating Cost Savings and Marginal Cost of Steam



One of the most powerful applications of such models is their use for on-line real time optimization of the operating policy for the CHP system. This has been done at many of the manufacturing sites owned by progressive companies like Union Carbide, BASF, and Chevron.

CONCLUSION

CHP simulation models are a convenient and reliable tool to evaluate ideas for efficiency improvement and cost reduction. They provide accurate estimates of operating costs, and can be used for online real-time optimization.

The cost of developing a model using electronic spreadsheets is very modest (in the range of \$10 – 20K, depending on complexity) compared to the potential benefits.

It is recommended that this tool be adopted by industry for energy cost accounting and to improve energy efficiency, with attendant reduction in operating cost and emissions of greenhouse gases to the environment.

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NOMENCLATURE

H enthalpy of steam
h enthalpy of liquid
kw kilowatts
kwh kilowatt-hours
P pressure

S steam (flow parameter)
T temperature
V vapor (flow parameter)
h efficiency, percentage

ABBREVIATIONS

BD blowdown
BFW boiler feed water
DA deaerator
DI De-ionized (water)
DSH desuperheating
HP high pressure
i inlet (as subscript)
IP intermediate pressure
K 1000
L liquid (as subscript)
LP low-pressure
MM million
MP medium pressure
o outlet (as subscript)
PRV pressure reducing valve
S steam (as subscript)
ST steam turbine
V vapor (as subscript)